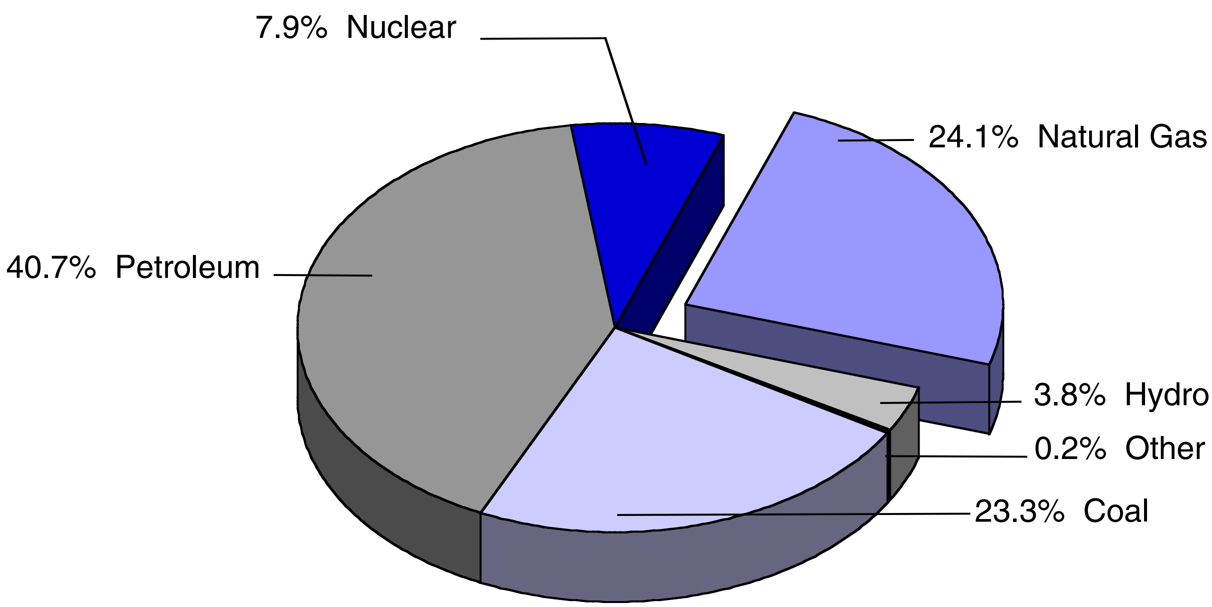
Conclusions

The emphasis on natural gas is good news for the economy, the environment, and society as a whole. In recent years, the United States has enjoyed a thriving economy, which has been driven in part by the ready availability of energy at competitive prices. Natural gas has played a vital role in meeting those energy requirements and today provides almost a quarter of the nation's energy portfolio (Figure 1). As this study demonstrates, natural gas can be a growing source of energy to power our economy for many years to come.

Actual U.S. gas demand has outpaced the 1992 study High Reference Case projection by more than 1 TCF over the period from 1990 through 1998 (Figure 2). This 1999 study now projects that U.S. gas demand will grow from 22 TCF (including net storage fill) in 1998 to approximately 29 TCF in 2010 and could rise beyond 31 TCF in 2015. Each key consumption sector—residential, commercial, industrial, and electricity generation—will increase (Figure 3a). However, the electricity generation sector alone will account for almost 50% of the increase through 2010 (Figure 3b). Over 110 gigawatts of new gas-fired generation capacity is projected to go into service by 2010, and a total of 140 gigawatts by 2015. Natural gas is now the preferred fuel for new electricity generation facilities, with 96% of the more than 200 recently announced new generation projects planning to burn natural gas. This dramatic shift to natural gas is driven by improved efficiencies, lower capital costs, reduced construction time, more expeditious permitting of natural gas-burning facilities, and environmental compliance advantages. However, the service requirements and price sensitivity of this additional load present many challenges to suppliers and transporters of natural gas.

Figure 1. Total U.S. Energy Consumption
By Primary Energy Source, 1998

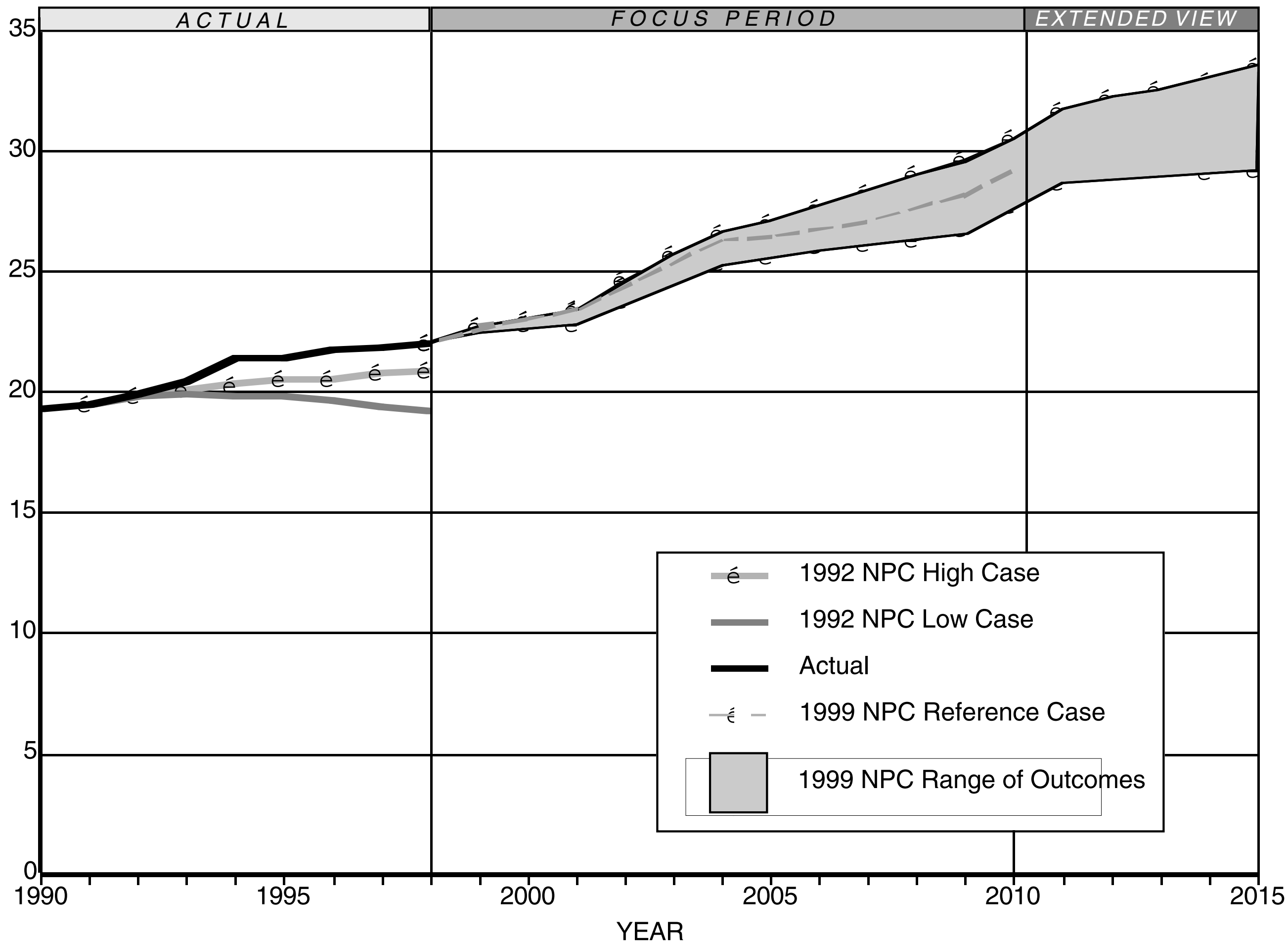


Source: DOE/EIA, Monthly Energy Review, September 1999

- Natural gas supplies almost a quarter of the nation's energy needs.

Figure 2. U.S. Natural Gas Demand

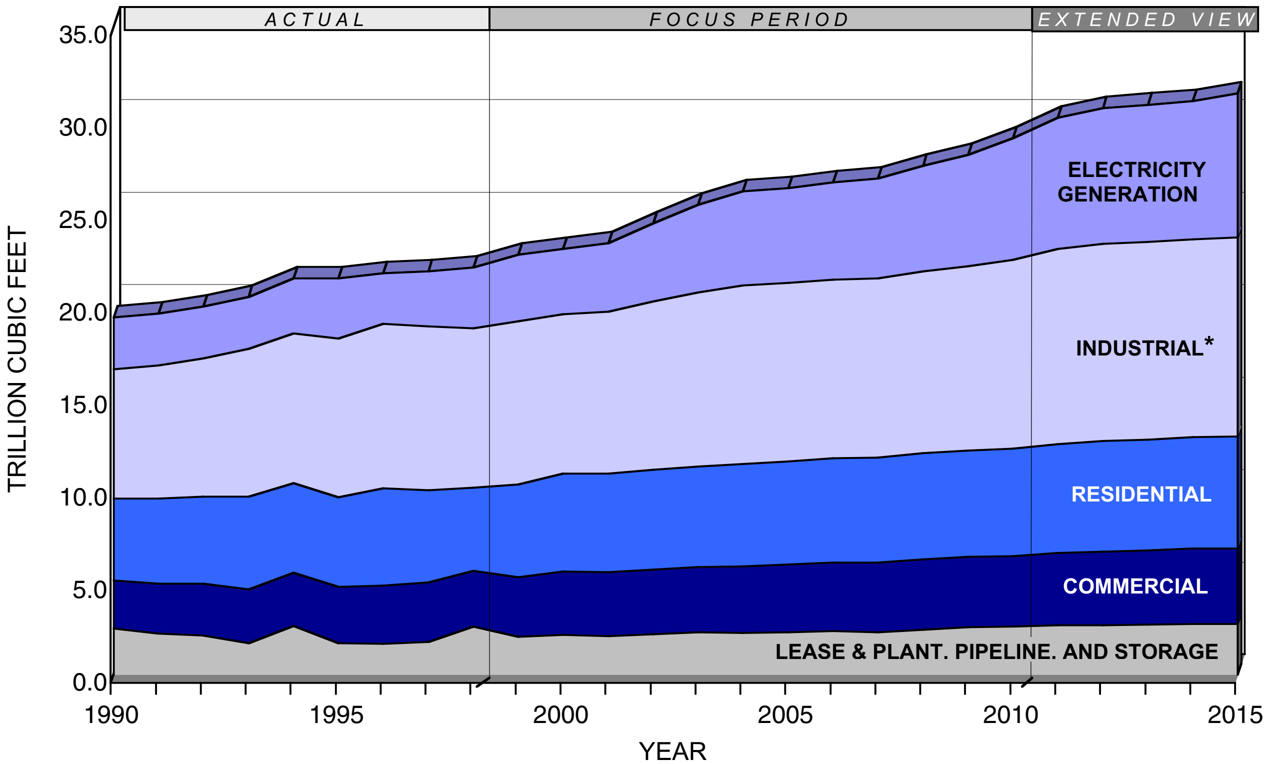
Comparison of 1992 and 1999 NPC Study Results



- Demand has exceeded the 1992 high case projection.
- Demand growth is expected to increase to 29 TCF by 2010, and increase beyond 31 TCF by 2015.
- Additional 7 TCF/year of gas supply will be needed by 2010.

Source of historical data: DOE/EIA, Natural Gas Monthly, September 1999

Figure 3a. U.S. Natural Gas Demand By Sector

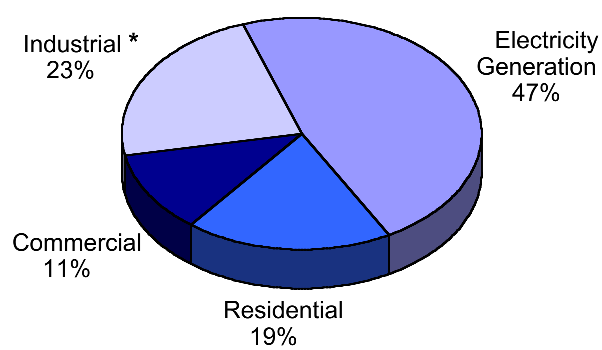


- Demand will grow in all sectors.

- Almost 50% of demand growth will be due to electricity generation.

Figure 3b. Growth in Reference Case Demand, 1998–2010

(Distribution of 7 TCF Increase by Sector)



** Historical data include all gas use for industrial cogeneration and independent power producers; all gas for new power plants except cogeneration is included in the electricity generation sector.*

Source: DOE/EIA, Natural Gas Monthly, September 1999

Growth in gas demand will remain subject to changes in such key variables as growth in the economy, price of competing fuels, nuclear retirements, and the capacity utilization of coal-fired electricity generation plants. For example, if 30 gigawatts of nuclear capacity are retired rather than the 15 gigawatts assumed in the Reference Case, demand could increase another 0.7 TCF. If coal capacity utilization remains at current levels instead of increasing from 64% to 75% as assumed in the Reference Case, demand could rise as much as 1.7 TCF. New environmental regulations, beyond those that are currently scheduled for implementation, have not been factored into this analysis and could also further increase natural gas demand. While this study did not attempt to quantify the impacts of additional environmental regulations on demand, incremental increases from Kyoto-related regulation were estimated in independent studies at 2–12% by the Energy Information Administration and 10–22% by the Edison Electric Institute beyond their respective reference cases.

The role that natural gas plays in improving the nation's environment has been widely recognized. A recent Minerals Management Service (MMS) report, *OCS Resource Management and Sustainable Development* (September l999), pointed out the benefits of natural gas:

> Natural gas is the least polluting fossil fuel. It is thought by many, including the present administration, to be the fuel of the early part of the next century that will power our economy into the sustainable fuels of the later decades and beyond. Even in the short run, conversion of more of our fuel burning facilities to natural gas will greatly diminish air pollution and improve the long run sustainability of forests, waters, and farmlands now being negatively affected by acid deposition.

The MMS report also noted the following regarding income from offshore resources:

> …royalties and taxes enable government to carry on programs which are beneficial to the oil and gas industry as well as society as

a whole. For example, an average of 60 percent of the collections from Federal offshore sources [$126 billion since offshore leasing began in 1953] went into the U.S. Treasury General Fund. Among other expenditures the Government uses a portion of these funds to invest in social infrastructure, which helps make the U.S. economy one of the most productive in the world. One of the areas in which some of this money is invested is in renewable energy, including many forms of energy conservation.

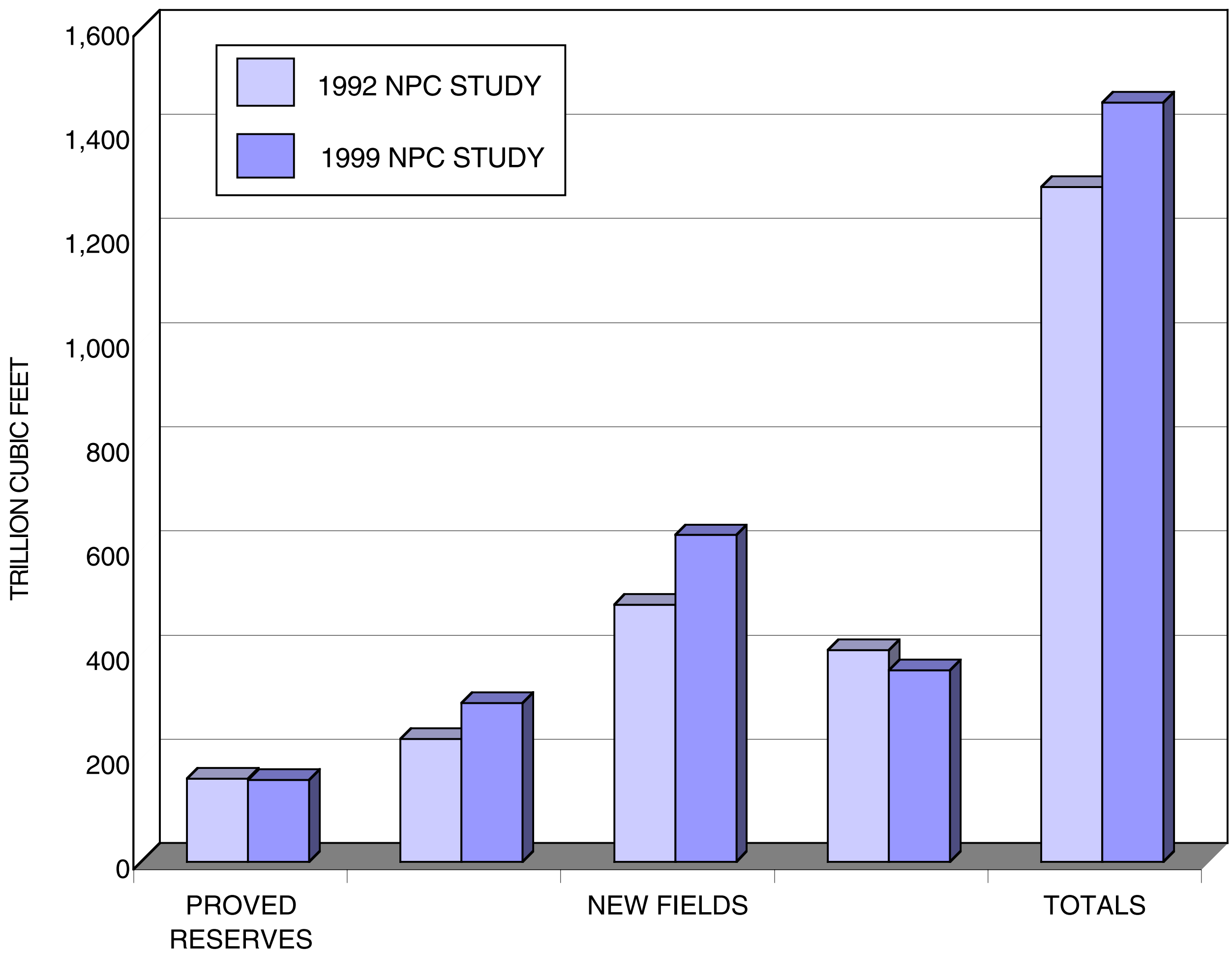
In onshore areas, federal, state, and local governments receive royalty income and collect taxes from natural gas production. The revenues that are collected from these sources allow these entities to provide essential services expected by their citizens, such as funding for education.

This study estimates the U.S. natural gas resource base, excluding Alaska, to be 1,466 TCF (Figure 4). This total represents a net increase of 171 TCF over the 1,295 TCF estimated in the 1992 study. Taking into account the 124 TCF that has been produced in the lower-48 states since then, the estimate of the resource base has increased 23% since the last study. The increase is largely due to technology breakthroughs that have opened new frontiers such as the deepwater Gulf of Mexico and have provided improved information and better tools for evaluating—and more fully recovering—resources.

U.S. gas demand will be filled with U.S. production, along with increasing volumes from Canada and a small, but growing, contribution from liquefied natural gas (LNG) imports (Figure 5a). Two regions—deepwater Gulf of Mexico and the Rockies—will contribute most significantly to the new supply (Figure 5b). U.S. production is projected to increase from 19 TCF in 1998 to 25 TCF in 2010, and could approach 27 TCF in 2015. Deeper wells, deeper water, and nonconventional sources will be key to future supply. For example, deepwater production (water depths greater than 200 meters), which in 1998 provided 0.8 TCF annually, will increase to over 4.5 TCF in 2010 (Figure 6). Onshore production from nonconventional formations is projected to increase by 50% from 4.4 TCF in 1998 to almost 7 TCF in 2010, with much of it coming from

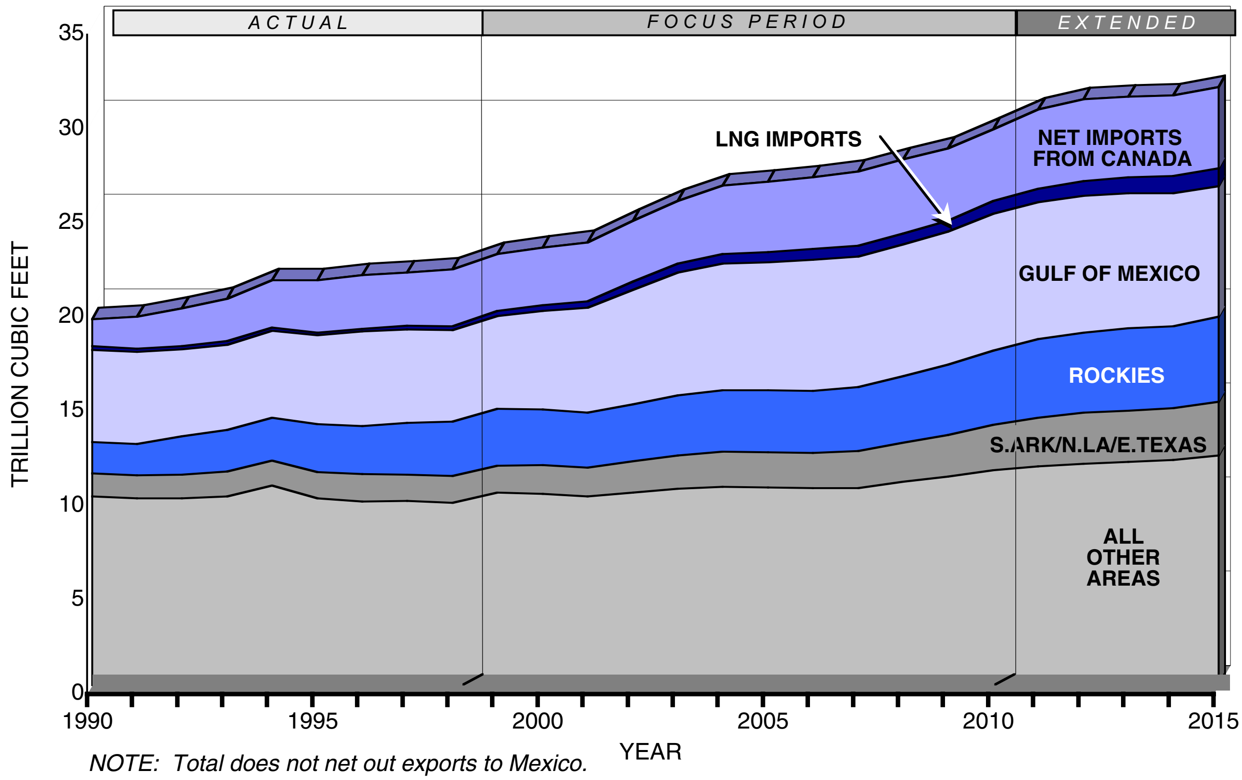
Figure 4. U.S. Lower-48 Natural Gas Resource Base Estimates

Comparison of 1992 and 1999 NPC Study Results



- Estimate of remaining resource base has grown 171 TCF to 1,466 TCF.
- Resource base estimate increased 23%, considering 124 TCF of production.
- Growth is primarily from New Fields, especially in deep water.

Figure 5a. U.S. Natural Gas Supply By Source

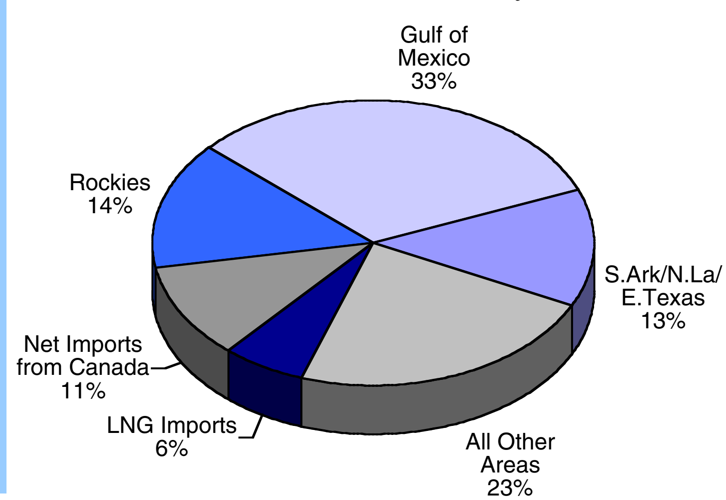


NOTE: Total does not net out exports to Mexico.

- Natural gas demand will be met primarily with domestic resources.
- Highest growth in U.S. production will be from Gulf of Mexico and Rockies.
- Canada will continue to be an important source of supply.

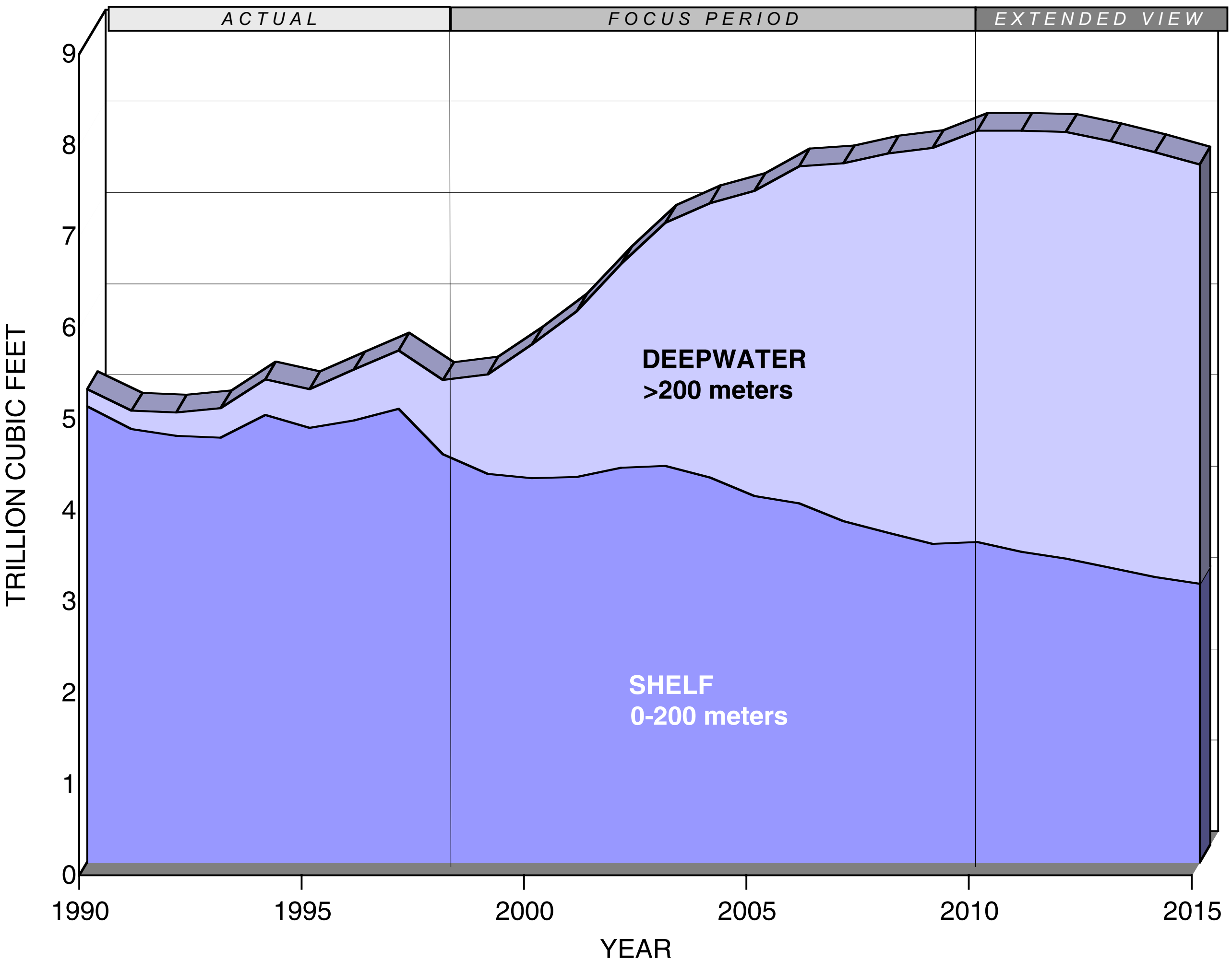
Figure 5b. Growth in Reference Case Supply, 1998–2010

(Distribution of 7 TCF Increase by Source)



Source of historical data: DOE/EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Reports, 1990–1997

Figure 6. U.S. Gulf of Mexico Natural Gas Production



- Gulf of Mexico production increases by 2.7 TCF by 2010.
- Deepwater production increases from less than 1 to over 4.5 TCF/year.
- Gradual decline is projected for shelf production.

Source of historical data: Dwights/PI production reports, June 1999 the Rocky Mountain region. By 2015, nonconventional gas production could be approaching 9 TCF. Production is likely to decrease in more traditional areas such as the Gulf of Mexico shelf and onshore Louisiana, each dropping by roughly one-third by 2015. It is important to note that approximately 14% of current natural gas supply is "associated," meaning that it is produced from oil wells. This associated gas will continue to be an important component of the overall supply, particularly in deepwater Gulf of Mexico.

Imports from Canada are projected to increase from 3 TCF in 1998 to almost 4 TCF by 2010, continuing to represent 13–14% of U.S. demand. Canada's remaining resource base is estimated at approximately 670 TCF in this study, down from 740 TCF in 1992. The decrease in the estimated Canadian resource base is due to depletion and reassessment of the nonconventional resources. Challenges similar to those confronting the U.S. industry will be faced by the Canadian producers, compounded by the fact that much of this gas is in frontier areas such as the MacKenzie Delta in far northwest Canada. Reaching this frontier will require significant capital expenditures as well as considerable lead times. Continued cooperation between the United States and Canada will be essential to ensure the timely availability of Canadian gas.

LNG imports are projected to reach a maximum of approximately 0.9 TCF, based on a 75% average capacity utilization rate for existing facilities. The assumption was made that no additional LNG import facilities would be built in the 1999–2015 period. Also, the assumption was made that exports to Mexico would reach a maximum of 0.4 TCF to serve Mexico's gas demand near the U.S. border.

The infrastructure required to deliver gas to market must be optimized and expanded to accommodate the increase in demand as well as the changing logistics of getting new supply to new customers. Future needs include new pipelines to reach supplies in the frontier regions, expansion of existing pipeline systems, new laterals to serve electricity plants, and expansion and construction of storage facilities to meet seasonal and peak-day requirements. By 2015, more than 14 million new customers will be added to the natural gas delivery system. To serve this growing market through 2015, over 38,000 miles of new transmission line are projected to be needed as well as 263,000 miles of distribution mains and almost 0.8 TCF of new working gas storage capacity.

The current delivery system (transmission, distribution, and storage) was built and optimized over decades to meet the design peak-day requirements of firm service customers that were primarily residential, commercial, and to a lesser extent, industrial customers. The anticipated growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as peak-day requirements that will increase from 111 BCF per day in 1997 to over 152 BCF per day in 2015. Meeting requirements of the electricity generators on a significantly larger scale will entail changes in operational procedures, communications, tariffs, and contracting. Further, these changes must be accomplished without degrading the historically reliable service to the residential, commercial, and industrial markets.

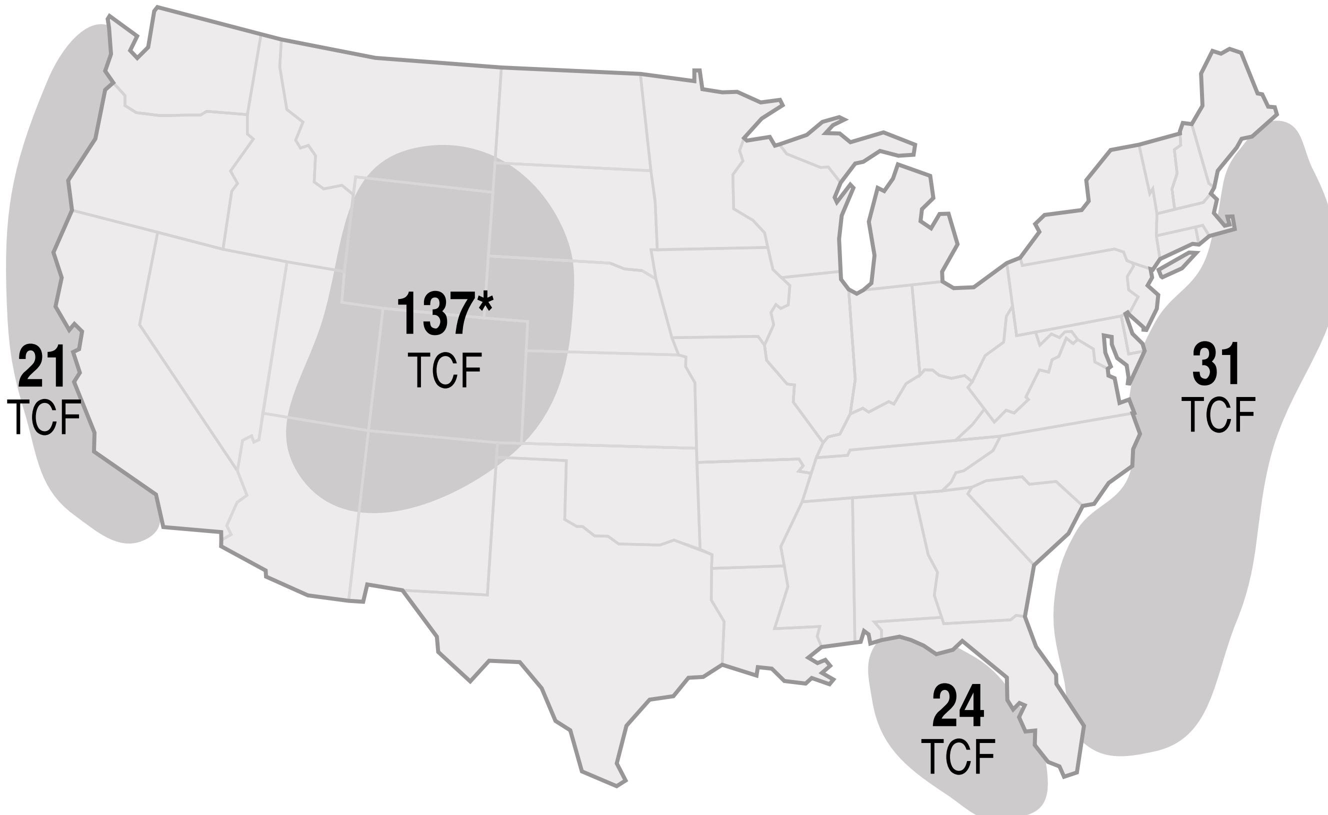
The Council believes that an unprecedented and cooperative effort among industry, government, and other stakeholders will be required to develop production from new and existing fields and build infrastructure at sufficient rates to meet the high level of demand indicated in this study. The ability to meet the anticipated demand hinges on addressing the following critical factors: access, technology, financial requirements, skilled workers, drilling rigs, lead times, and changes in customer requirements.

CRITICAL FACTORS

Access

Much of the nation's resource base resides on federal lands or in federal waters, yet a large portion of this resource base is not open to either assessment or development (Figure 7). Two of the most promising regions for future gas production, the Rocky Mountains and the Gulf of Mexico, currently have

Figure 7. U.S. Lower-48 Natural Gas Resources
Subject to Access Restrictions



Approximately 29 TCF of the Rockies gas resources are closed to development and 108 TCF are available with restrictions.

- Significant amount of resource is subject to access restrictions.
- These areas are close to large and growing population centers.

significant access restrictions. For example, an estimated 40%—or 137 TCF—of potential gas resource in the Rockies is on federal land that is either closed to exploration or is open under restrictive provisions. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. The eastern Gulf of Mexico is largely closed to exploration and the limited areas that are now open are the subject of political debate. The proposed Lease Sale 181 scheduled for December 2001 in the eastern Gulf of Mexico is the first such sale in this area since the late 1980s, yet only covers a small portion of the entire area. The East Coast of the United States is completely closed to development while Canada is pursuing its East Coast gas resources, as demonstrated by the recent Sable Island development off the coast of Nova Scotia. In addition, drilling on the West Coast of the United States also faces strong restrictions, while offshore British Columbia is opening up to greater exploration and production.

This study assumes that planned lease sales for areas in the Outer Continental Shelf (OCS) will continue on schedule and that further restrictions will not be applied to those lands currently open to development. These assumptions may be optimistic in light of recent statements by some public officials. Further restrictions would increase the challenge of meeting the projected gas demand with cost-competitive supply. Conversely, opening hydrocarbon-rich areas for development would greatly improve the industry's potential to respond to market needs.

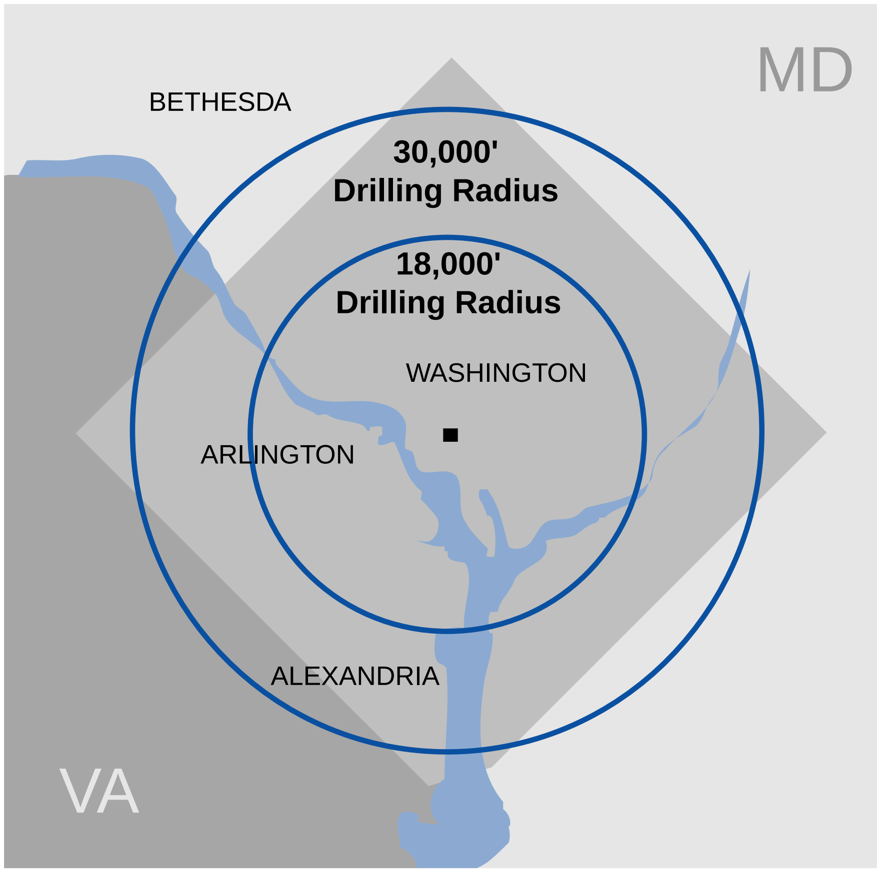
Access is also an issue for the transmission and distribution sectors of the industry as they seek rights of way for pipeline facilities. The permitting and construction processes have become more complex over time. Restrictions for wetlands, wildlife refuges, and other sensitive federal and state lands impact the routing and construction of pipelines throughout the United States, not just the frontier areas. Other issues arise from the encroachment of urban development on existing rights of way, heightened community awareness of and resistance to pipeline construction, and increasingly restrictive government policies and regulations. Resolution of these issues—which must be addressed for each pipeline addition—is costly and time-consuming and often results in project delays or abandonment of projects.

Most of the access restrictions are due to environmental concerns or multiple-use conflicts even though industry has made tremendous improvements in reducing the "footprint" of exploration, production, and transportation activities, and in maintaining clean, safe operations. As stated in a recent Department of Energy report, "Resources underlying arctic regions, coastal and deep offshore waters, sensitive wetlands and wildlife habitats, public lands, and even cities and airports can now be contacted and produced without disrupting surface features above them."[1] An excellent example of the dramatic improvements in environmental footprints can be found in Alaska where significant efforts have been made to minimize the impact of drilling operations on the tundra. A report to the Secretary of the Interior in 1997 by the Alaska Oil and Gas Association stated that in the 1970s, pads for drilling operations took up about 65 acres whereas the pads for recent operations are now less than 10 acres. The report further explained that cluster drilling and extended reach drilling enable producers to access hydrocarbon deposits 3–4 miles away from the pad, thus greatly reducing the number of drilling locations and associated roads and pipelines. Lateral extensions of 18,000 feet are common on the Alaskan North Slope today. More recent efforts in other parts of the world have extended the drilling reach to 5–6 miles. This has the same effect as setting up drilling operations on the White House lawn and extracting hydrocarbons from beneath most of Washington, D.C., and into its suburbs (Figure 8).

Equally impressive improvements in environmental impacts have been demonstrated offshore, where much of the natural gas production is associated with oil production. As reported to President Clinton by the Cabinet in *Turning to the Sea: America's Ocean Future* (September 1999), "Advances in technology have made offshore oil and gas production cleaner and safer than ever. Since

[1] U.S. Department of Energy, Office of Fossil Energy, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology*, October 1999, pg. 13.

Figure 8. Reducing Environmental Impact with Extended-Reach Drilling.



- Improvements in extended-reach drilling allow access to resources 5 to 6 miles from the drilling site.

- Similar technologies for minimizing environmental impact continue to be developed.

1980, 6.9 billion barrels of Outer Continental Shelf oil have been produced with a spillage rate of less than 0.001%. Despite these advances, however, environmental concerns have led to congressional and executive moratoria since 1981, and many of our coastal areas are now closed to new leasing through the year 2012."

This study has determined that access issues, and associated environmental concerns, must be addressed. Access to some portion of the federal gas resource base currently closed or significantly restricted to appraisal or development, as well as acquisition of rights of way, is essential to meeting the projected demand with cost-competitive gas supply.

Technology

Even though the estimated resource base is adequate to last many decades, technological challenges and the degree of difficulty in reaching, evaluating, and producing the resource base continue to escalate. The previously referenced report by the Office of Fossil Energy of the U.S. Department of Energy [2] highlights the importance of research and development to the oil and gas industry:

> In the past three decades, the petroleum business has transformed itself into a high-technology industry. Dramatic advances in technology for exploration, drilling and completion, production, and site restoration have enabled the industry to keep up with the ever-increasing demand for reliable supplies of oil and natural gas at reasonable prices. The productivity gains and cost reductions attributable to these advances have been widely described and broadly recognized… Looking forward, the domestic oil and gas industry will be challenged to continue extending the frontiers of

[2] Ibid, p.1.

technology. Ongoing advances in E&P productivity are essential if producers are to keep pace with steadily growing demand for oil and gas, both in the United States and world wide. Continuing innovation will also be needed to sustain the industry's leadership in the intensely competitive international arena, and to retain high-paying oil and gas industry jobs at home. Progressively cleaner, less intrusive, and more efficient technology will be instrumental in enhancing environmental protection in the future.

Technology improvements are particularly important given the more difficult conditions accompanying new resources. Deeper wells encounter extreme temperatures and pressures and increased potential for intensely corrosive environments. These conditions require high-strength materials and advanced drilling methods. Current deepwater endeavors involve exploration wells in over 8,000 feet of water and complex production projects in more than 5,000 feet of water. Subsea pipelines must be built to withstand powerful currents, shifting ocean floors and external pressures that are greater than those inside the pipe. Innovative design, fabrication, and installation techniques must emerge to enable these new resources to reach existing markets at attractive prices.

Technology improvements are also needed for expanding and managing the delivery system and improving efficiency at the burner-tip. The increased challenges of serving a growing market and changing load must not jeopardize the historical reliability and favorable economics of the transmission and distribution system. Pipelines and LDCs will continue to rely on technology for reducing operation and maintenance expenses and minimizing environmental impacts of facilities construction. Information and communications technology will play an ever-increasing role in safe and efficient operations as well as in supply management and customer service enhancements.

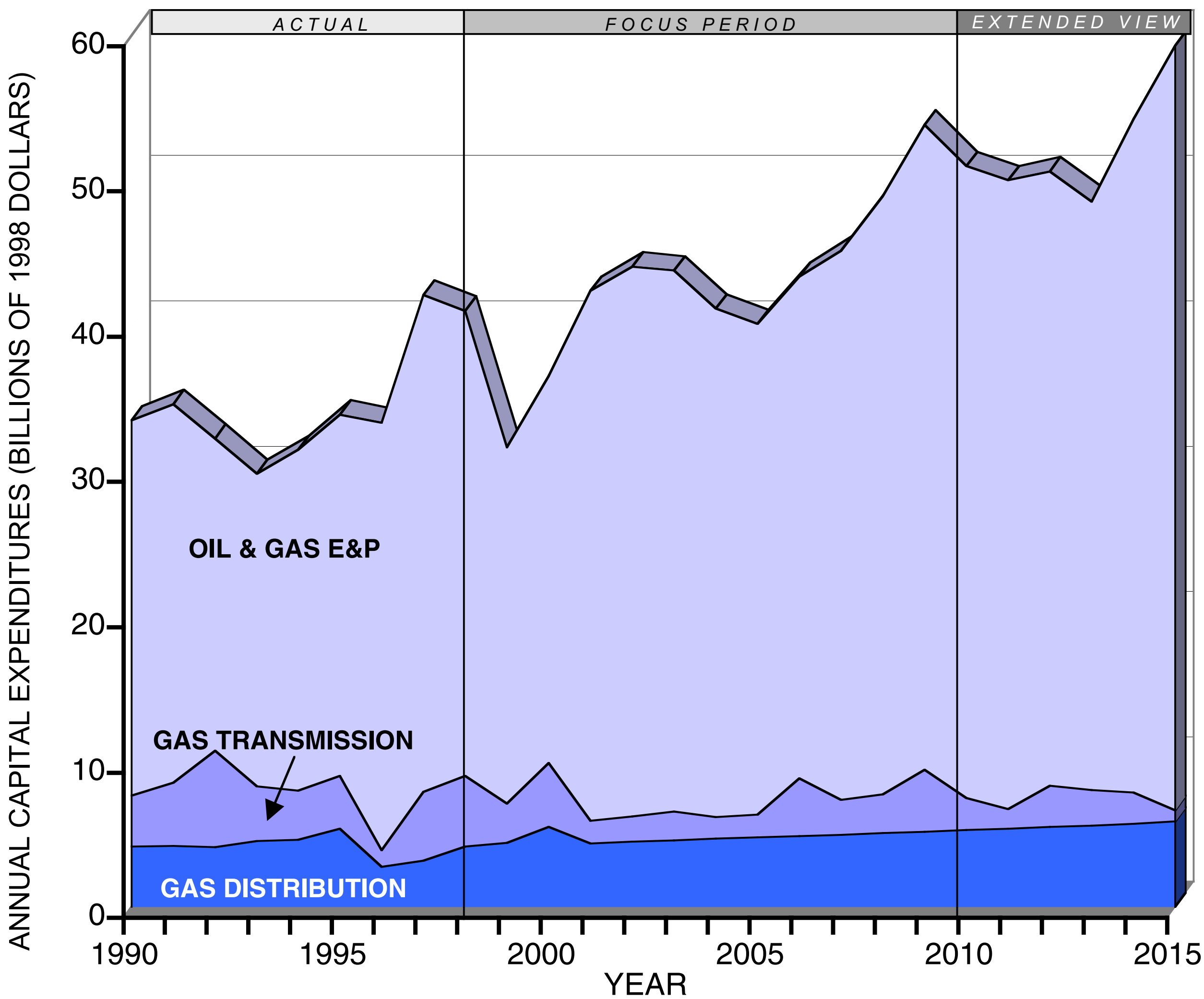
Technology advances are essential in all industry segments for improving operational efficiencies, reducing resource development time, increasing production, developing frontier areas, controlling costs, and minimizing environmental impact. This study assumes that technology improvements will continue at an aggressive pace. However, recent industry trends in research and development spending have raised concerns regarding this assumption. Industry restructuring, consolidations, and spending cuts have resulted in reductions in research budgets. Producers are turning to the service sectors to develop new technology for specific applications. Industry consortia have been formed to address critical technology challenges such as deepwater development. While many of these changes improve the efficiency with which research and development dollars are spent, concerns have been widely expressed that basic and long-term research are not being adequately addressed.

Financial Requirements

Adequate financial performance must be demonstrated in order to compete for and attract the investments required to meet the growing demand. Companies will need to balance short-term performance demands with long-term planning to achieve the needed growth. Almost $1.5 trillion ($1998) will be required to fund the industry through 2015. This amount includes over $700 billion for operating expenses and an estimated $781 billion for capital investments. Approximately $658 billion of capital is projected to be spent for oil and gas supply development and about $123 billion for transmission, storage, and distribution infrastructure expansion (Figure 9). This equates to an average annual increase in capital expenditures from $34 billion per year between 1990 and 1998 to $46 billion between 1999 and 2015. Many of these expenditures will involve higher risk projects—such as large deepwater projects or pipelines to new frontiers—each of which can easily exceed $1 billion.

While much of the required capital will come from reinvested cash flow, capital from outside the industry is essential to continued growth. To achieve this level of capital investment, industry must be able to compete with other investment opportunities. This poses a challenge to all sectors of the industry, many of which have historically delivered returns lower than the average reported for Standard and Poors 500 companies.

Figure 9. Capital Required for Expansion



** Because "associated" natural gas is produced with oil, expenditures for oil and gas have not been separated.*

- Substantial increase in capital expenditures will be required.
- Total capital expenditures for 1999–2015 will be $785 billion.

Source of historical data: AGA Gas Facts–1998, and estimates from EEA, Inc.

The transmission and distribution sectors of the industry also face challenges in attracting investments to future projects. Expanding the infrastructure of the delivery system to accommodate increased demand and changing requirements of new customers will involve changes in financial risks. For example, expiring long-term LDC contracts for pipeline capacity, which historically provided the financial backing for pipeline expansions, will be replaced by shorter term contracts with new non-utility customers. Uncertainty exists with future rate structures and obligations to serve, as electricity and gas restructuring continues. Industry participants and regulators must work together to find an appropriate balance for these risks so that the needed infrastructure expansions can be accomplished.

Skilled Workers

A significant concern of the industry is the future availability of skilled workers at all levels to produce the increased supply and construct the necessary infrastructure. Company consolidations and volatile fluctuations in oil prices have resulted in cuts in exploration and production budgets, leading to layoffs at all levels in exploration and production companies and in service/supply companies. Approximately 500,000 jobs have been eliminated from the industry since the early 1980s, with over 40,000 job cuts occurring in the producing sector alone in the past year. Simultaneous reduction in industry hiring rates in the last 20 years has resulted in a disproportionate percentage of the workforce reaching retirement age in the next decade—an average of 40% in a sampling of major producers. Furthermore, the next generation of workers is not choosing to enter the industry, as indicated by the significant decrease in enrollment in some energy-related college curricula since the mid-1980s. The oilfield service/supply sector faces a similar situation as many laborers and supervisory personnel have left the industry in search of more stable work. Higher wage scales are likely to be required to attract workers back into the industry.

Drilling Rigs

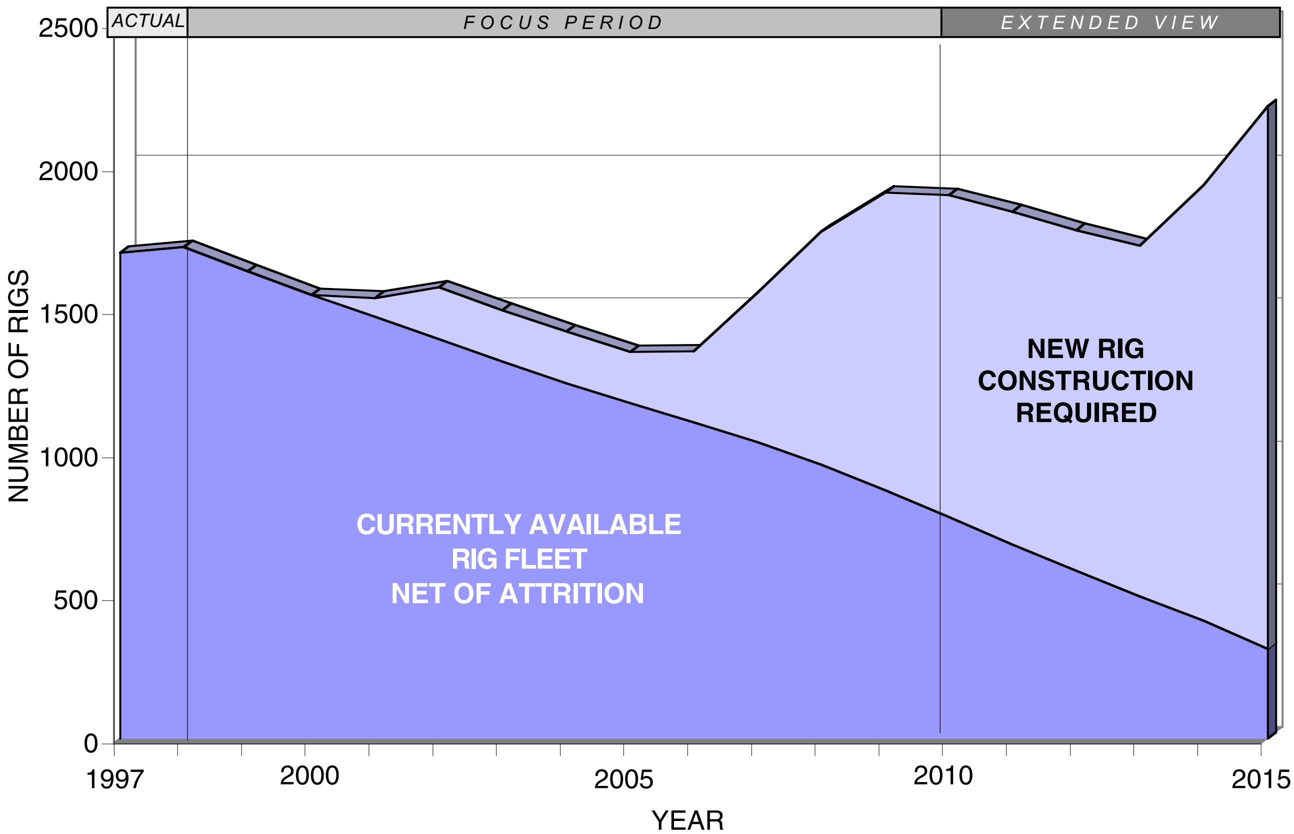
The U.S. drilling fleet must expand to undertake the dramatic increase in activity that will be required over the next decade to produce the additional supply. The total number of oil and gas wells drilled per year (including dry holes) will have to double, from approximately 24,000 in 1998 to over 48,000 by 2015. Even taking into account anticipated improvements in drilling efficiencies, approximately 2,300 active rigs (over 2,100 land rigs and 180 offshore) would be needed to achieve this level of drilling. This represents an 80% increase over the 1,250 average active rig count estimated for 1999.

Rig availability, which is crucial to exploration and development, will be a challenge for the industry. The oilfield supply and service sectors have been hit particularly hard by the boom and bust cycles. Very few new onshore drilling rigs have been built since the mid-1980s. If the 5% per year historical attrition rate were to continue, most of the existing 1,700 onshore rigs would be retired by 2015 and a total of almost 1,900 onshore rigs would have to be built (Figure 10). Additions to the offshore rig fleet will also be needed and are projected to include 10 deepwater drilling rigs, 32 platform rigs, and 30 jack-up rigs and barges (Figure 11). Although the number of new offshore rigs is smaller, the average cost per rig is significantly higher than that of onshore rigs. The drilling sector and the manufacturers of drilling equipment are not currently positioned to undertake this level of expansion.

Lead Times

Reduction of development lead times—from lease acquisition and prospect identification, to the beginning of exploration, to pipeline construction for delivery to the burner tip—is critical to meeting the gas demand projected in this study. For example, as many as 10 years—or two-thirds of the time period of this study—may elapse between the time a block in the offshore is leased until production flows to market. Industry and government are working diligently to reduce development time by streamlining processes and applying new technology. However, access limitations and cumbersome permitting and approval

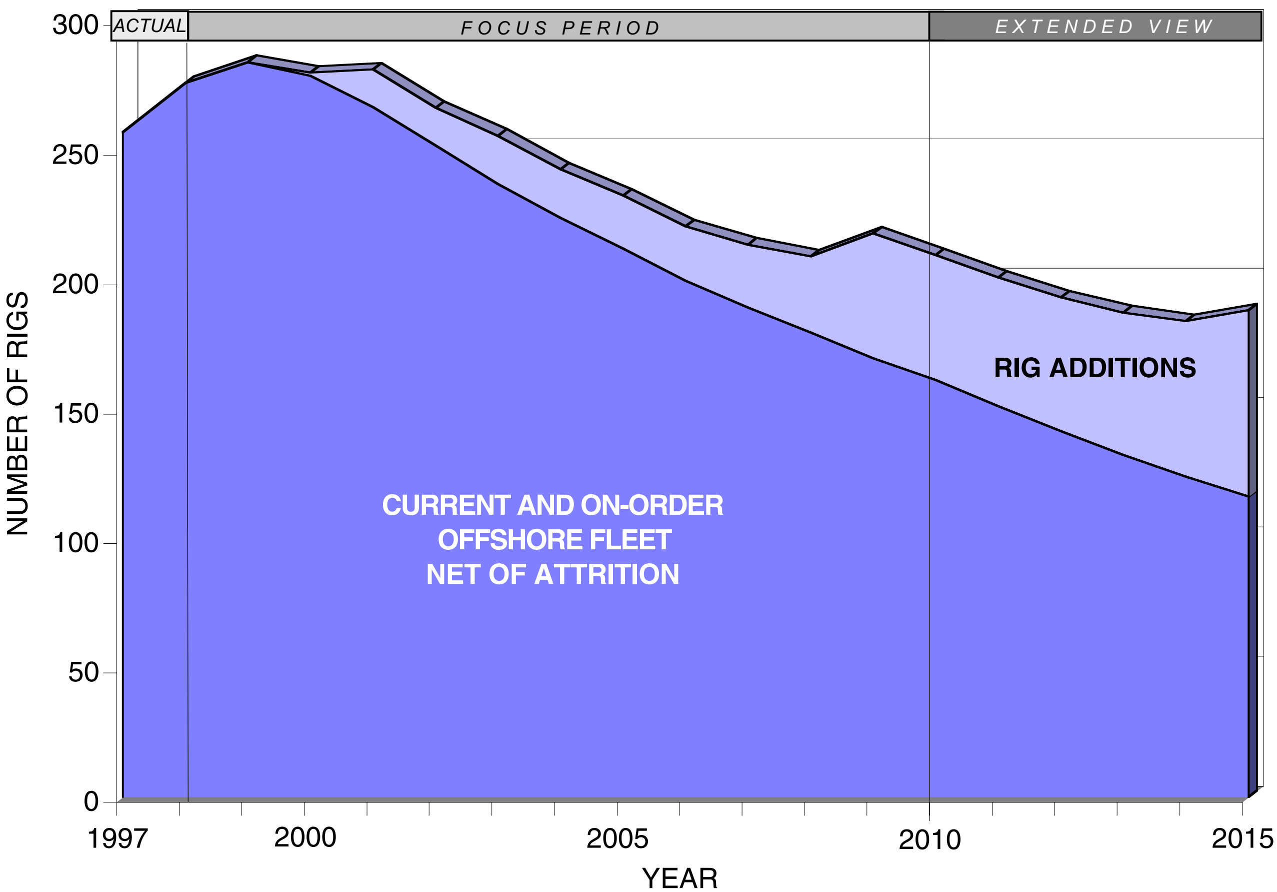
Figure 10. Onshore Drilling Rig Fleet



- 1,900 new onshore rigs will be needed through 2015, as the number of wells drilled per year doubles.
- Very few onshore rigs have been built since the 1980s.
- Availability of skilled workers to build and operate these rigs is a concern.

Source of historical data: <u>Reed Rig Census,</u> 1997–1998, and estimates from EEA, Inc.

Figure 11. Offshore Drilling Rig Fleet



- 72 additional offshore rigs will be needed.
- Additions may be from reactivations, new construction, or relocations.
- Availability of skilled workers is also a concern.

Source of historical data: Offshore Data Services, Rig Locator, September 24,1999 processes often negate those improvements. For example, increases in time required to perform studies previously conducted by government agencies, and obtain multi-agency permits have resulted in production project delays of up to two years on federal lands in the Rocky Mountain region. While the MMS has improved the approval process for offshore development by serving as the facilitator for the process, production and pipeline projects on land still require extensive interactions with multiple levels and agencies of federal, state and local governments. For example, the recently constructed Portland Natural Gas Transmission System involved the acquisition of over 150 permits and/or approvals from federal, state, and municipal government agencies. Most of the agencies involved in these processes have different data requirements, forms, and processes. Additional improvements are needed immediately in order to impact the development in the outer years of this study.

Changing Customer Needs

The ongoing regulatory restructuring of the natural gas and electricity markets changes the roles and responsibilities of all industry participants. As restructuring continues to unfold at the state level, the roles and obligations of LDCs and electric utilities will be changing. Other energy market participants may accept some aspects of the former roles of the LDCs and electric utilities as services are unbundled. These other participants, such as producers, generators, marketers, energy service providers, and end-users will contract for and use capacity differently than the LDCs and traditional electric utilities. In addition, new flexible services will be required to meet the anticipated increase in gas demand for electricity generation as projected in this study. For example, natural gas-fueled turbines (simple and combined cycle) have unique operating requirements in terms of inlet pressures and operations. Since electricity cannot be stored, the electricity generation systems must be constantly monitored and adjusted to change output instantaneously as electricity demand changes. Thus corresponding changes in natural gas demand occur constantly throughout the day. These changes in roles, services, and customer requirements will cause all sectors of both the natural gas and electricity industries to manage their assets differently.

SENSITIVITY ANALYSES

As discussed earlier in this report, sensitivity analyses provided some important information regarding the importance of the critical factors (see Figure 12a). Demand, for example, can increase by 0.6 TCF in 2010 if gross domestic product (GDP) grows by 3.0% annually instead of 2.5%. Conversely, GDP growth of 2.0% could result in a decrease in demand of 0.9 TCF by 2010. If crude oil price averaged $22.00 rather than $18.50 as assumed in the Reference Case, demand could increase by 0.7 TCF in 2010. However, demand would be 1.0 TCF lower if crude oil price averaged $15.00.

The model's output on price also served as a gauge for quantifying the impact of certain assumptions (Figures 12b and 13). While the model projects an average production weighted U.S. wellhead gas price through 2010 of approximately $2.74 per million British thermal units (MMBtu), prices in the sensitivity analyses change significantly. For example, the model projects that gas prices could be as much as $0.32 per MMBtu lower in 2010 if technology improvements are significantly better than assumed in the Reference Case. Conversely, a slower pace of technology improvements could drive the price up by $0.27 per MMBtu.

The single most significant assumption in the Reference Case is the size of the resource base. The model projects that the price of gas could be lowered by as much as $0.96 per MMBtu in 2010 if the economically recoverable resource base were found to be 250 TCF larger than assumed in the Reference Case. In this case, demand increases by 1.9 TCF and U.S. production increases by 1.5 TCF. A second sensitivity was run to examine the impact of a smaller resource base, although it should be noted that the resource base estimates have always increased over time. If estimates of the resource base are lowered by 250 TCF, prices could be as much as $0.56 per MMBtu higher, demand would be 1.5 TCF lower, and U.S. production would be 1.6 TCF lower. While this sensitivity was run to evaluate the impact of learning more about the resource base, it also provides some insight to the impact of access restrictions. Access is an important factor because it removes potential supply from the available resource base.

Figure 12a. Influence of Key Assumptions on Natural Gas Demand

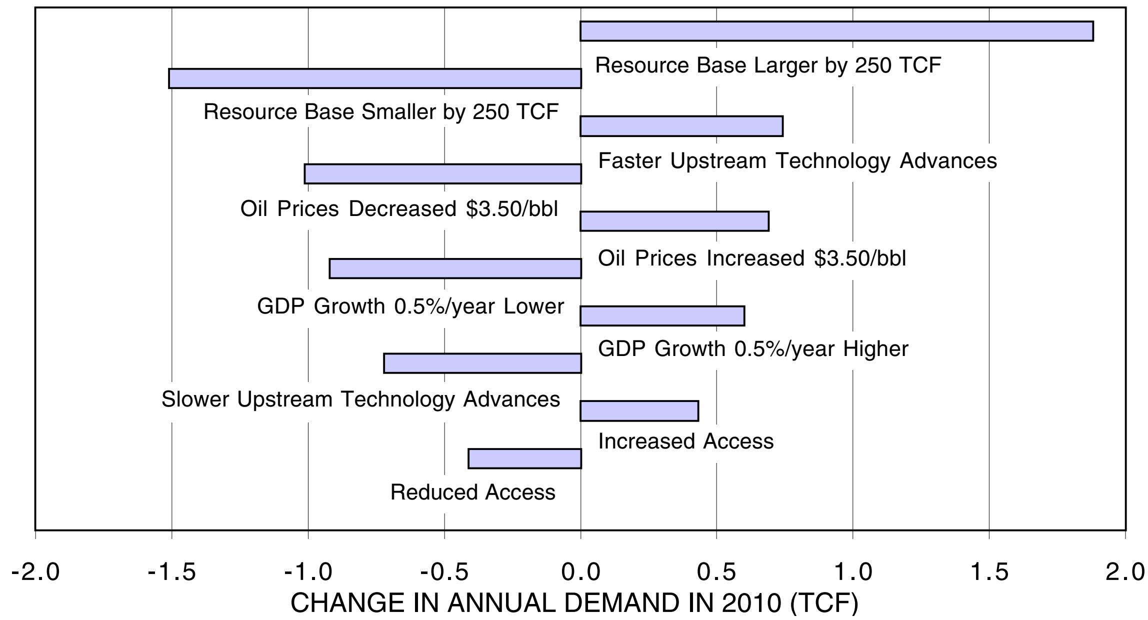
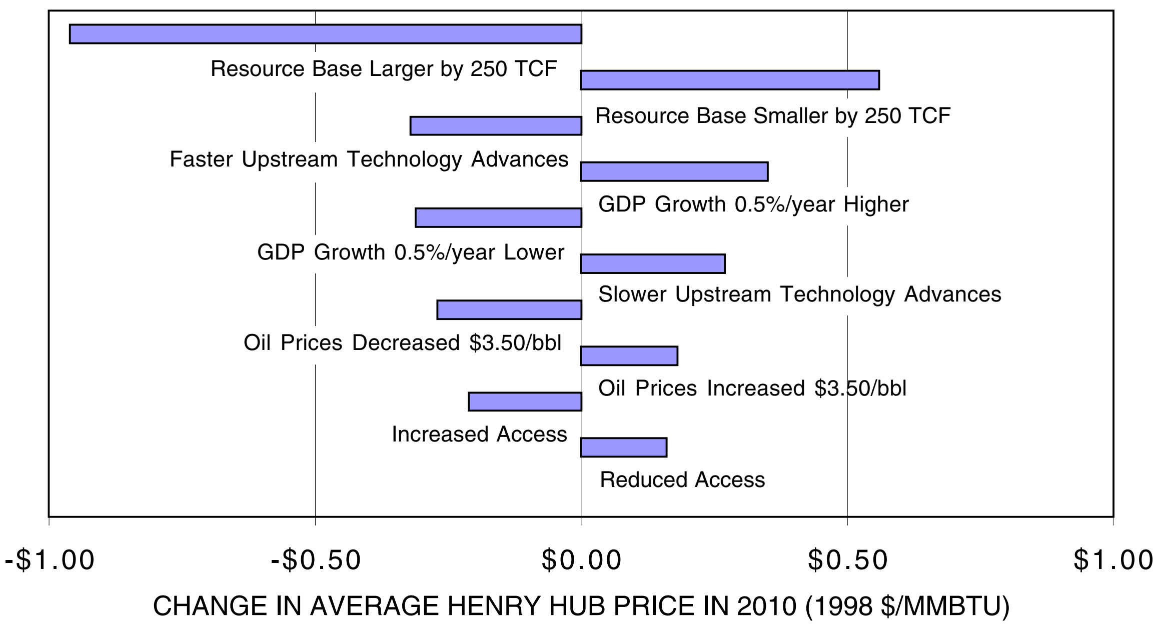


Figure 12b. Influence of Key Assumptions on Natural Gas Price

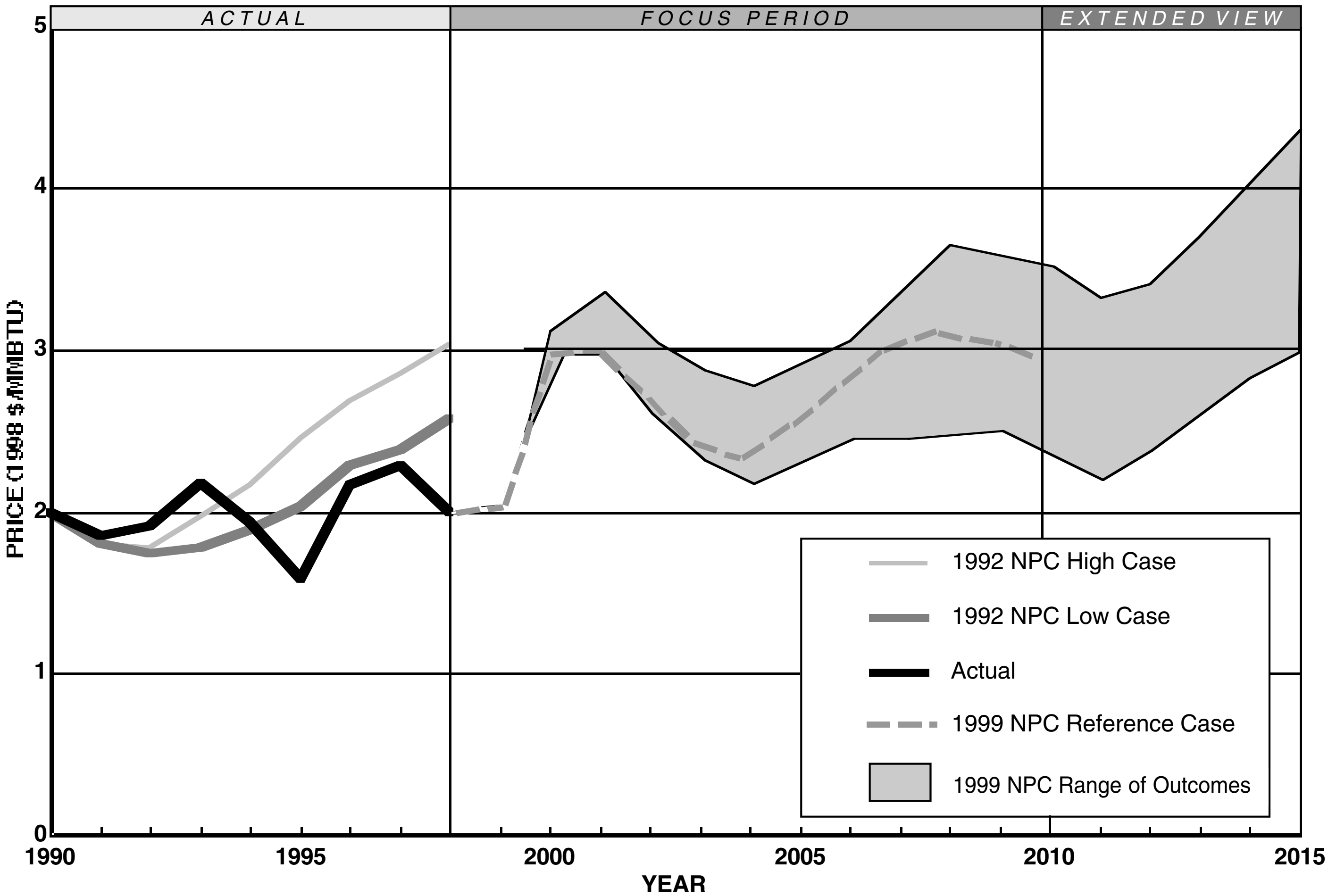


- A 15-20% change in the resource base has substantial impact on projected price and demand.
- Pace of technological advancement also has significant influence on projected price and demand.

NOTE: See Figures 14a and 14b for more details on resource base and access cases.

Figure 13. Historical and Projected U.S. Natural Gas Prices*

Lower-48 Weighted Average Wellhead Price



** Prices are NOT intended to be a forecast. Seasonal factors such as abnormal weather and demand fluctuation have not been taken into account.*

- Actual price for 1991–1998 averaged $1.97 versus 1992 study projections of $2.06–2.34.
- Price volatility will likely continue.
- Sensitivity analyses demonstrate the range of outcomes for key assumptions.
- The market will ultimately determine the price of natural gas.

Source: DOE/EIA, Monthly Energy Review, September 1999

Access restrictions also limit the opportunity to better assess the resource size in those areas.

To better quantify the impact of access restrictions, two additional sensitivity cases were developed. The first case tightened access restrictions in the Rocky Mountain region and eliminated the planned Lease Sale 181. In this reduced access case, price increased $0.16 per MMBtu in 2010 and demand decreased by 0.4 TCF. U.S. production decreased by 0.5 TCF. The second sensitivity case relaxed access restrictions in the Rockies and made currently restricted offshore regions available for leasing in 2004. This increased access case resulted in an increase in U.S. production of 0.5 TCF in 2010, an increase in demand of 0.4 TCF and a corresponding decrease in price of $0.21 per MMBtu. More importantly, a dramatic shift occurred in the Extended View period of the increased access case with an increase in demand of 1.5 TCF in 2015, a corresponding increase in U.S. production of 1.6 TCF (primarily from the Rockies and the eastern Gulf of Mexico), and a corresponding decrease in price of $0.45 per MMBtu (Figures 14a and 14b).

The most important conclusion derived from these sensitivity analyses is that the future availability and cost of natural gas can be influenced. While some variables cannot be controlled, factors such as the rate of technology development, knowledge of the resource base, and access to the resource base can be impacted—either positively or negatively—by the actions of the industry and the government.

The Council wishes to emphasize that the price output of the model is not to be used as a forecast, but rather as an indicator of the relative influence of the critical factors and assumptions. Seasonal factors that affect price, such as abnormal weather and demand fluctuations, have not been taken into account. The market will ultimately determine the price of natural gas. However, actions can be taken by industry and government to ensure that adequate supply is available, that it can be delivered to the market, and that the ultimate price is competitive through the study period and beyond.

Figure 14a. Impact of Size of Resource Base and Access on U.S. Natural Gas Production

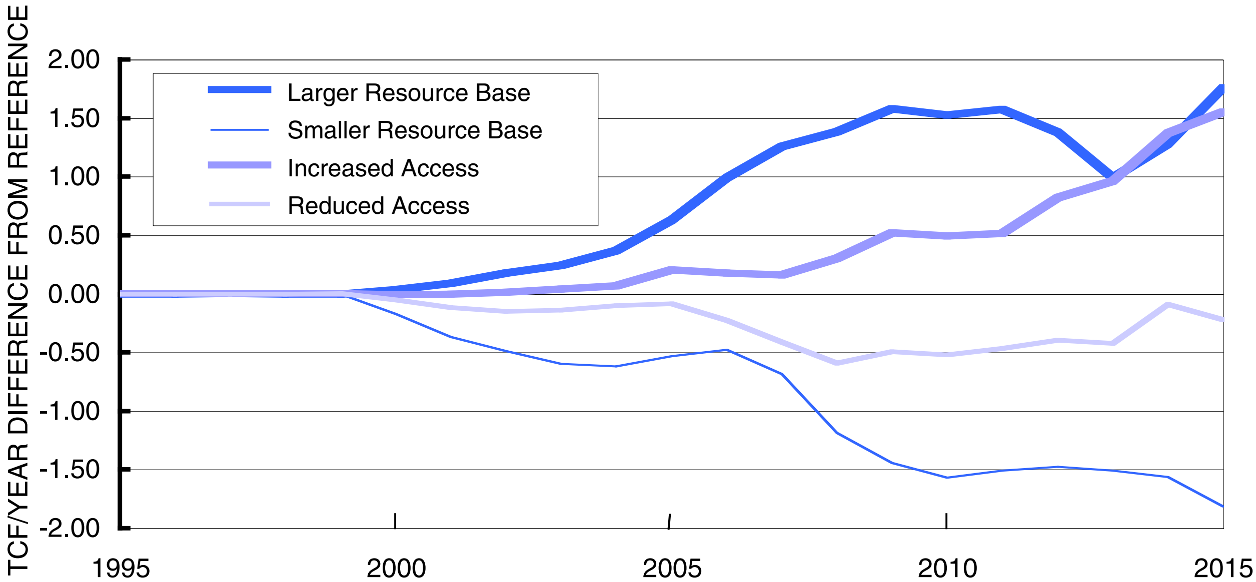
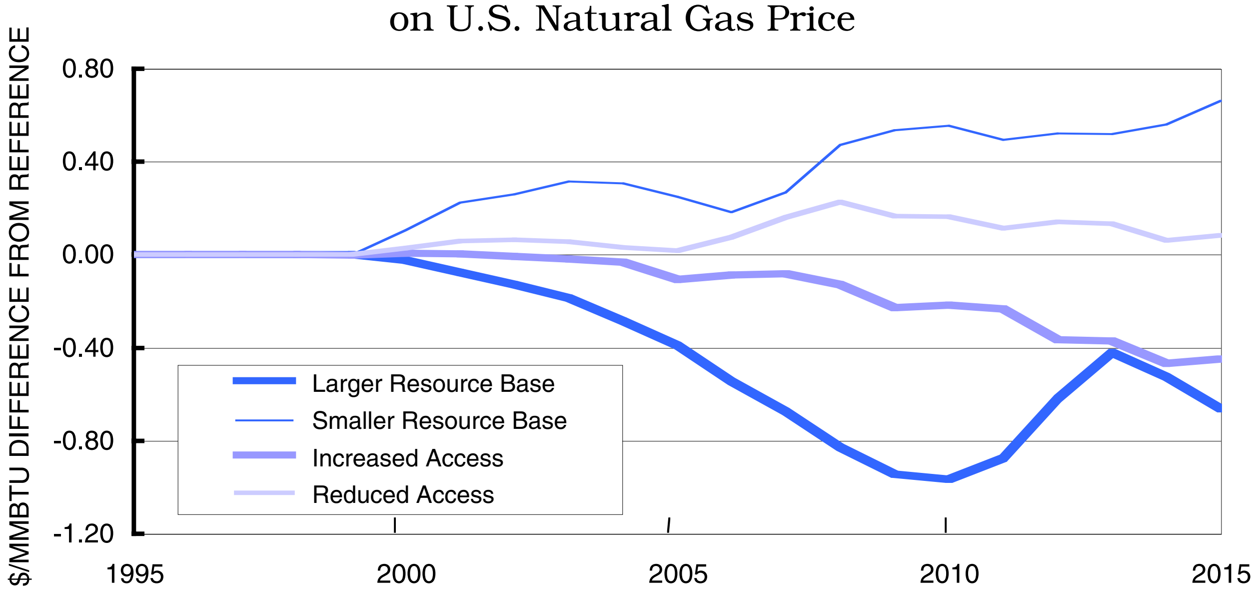


Figure 14b. Impact of Size of Resource Base and Access on U.S. Natural Gas Price



- Larger resource base would increase U.S. natural gas production 1.8 TCF in 2015 and decrease price $0.66.
- Smaller resource base would decrease U.S. natural gas production 1.8 TCF and increase price $0.66.
- Increased access would increase U.S. natural gas production 1.6 TCF in 2015 and decrease price $0.45.
- Reduced access would decrease U.S. natural gas production 0.2 TCF in 2015 and increase price $0.08.

In summary, affordable energy is necessary to sustain continued growth of the nation's economy and quality of life. Natural gas will play an important role, particularly as it helps the nation meet its environmental goals. By 2015, more than 14 million new customers will be connected to natural gas supply through over 300,000 miles of new transmission pipelines and distribution mains. Many more customers will use electricity that is fueled by natural gas as over 140 gigawatts of new electricity generation capacity—almost entirely gas-burning units—go into service. These new customers, as well as the existing customer base, are counting on long-term availability of reliable, competitively priced natural gas to meet their energy needs and to support the nation's environmental goals. Industry, government, and other stakeholders must act quickly, cooperatively, and purposefully to meet those expectations.